2 ReEDS Base Case Data

This section summarizes the key data inputs to the Base Case of the ReEDS model. The Base Case was developed simply as a point of departure for other analyses to be conducted with the ReEDS model. It does not represent a forecast of the future, but rather is a consensus scenario whose inputs depend strongly on others' results and forecasts. For example, the ReEDS Base Case derives many of its inputs from the EIA's *Annual Energy Outlook* (EIA 2009)—in particular, its fossil fuel price forecasts, and its electric-sector load-growth rates.

2.1 Financials

ReEDS optimizes the build-out of the electric power system based on projected life-cycle costs, which include capital costs and cumulative discounted operating costs over a fixed evaluation period. The "overnight" capital costs are adjusted to reflect the actual total cost of construction, including tax effects, interest during construction, and financing mechanisms. Table 1 provides a summary of the financial values used to produce the net capital and operating costs.

Table 1: Base Case Financial Assumptions

Name	Value	Notes and Sources
InflationRate	3%	Based on recent historical inflation rates.
Real Discount Rate	8.5%	Equivalent to weighted cost of capital. Based on EIA assumptions (EIA 2008c).
Debt/Equity Ratio	0	Consistent with the use of a weighted cost of capital for the real discount rate.
Real Interest Rate	0	Consistent with the use of a weighted cost of capital for the real discount rate.
Marginal Income Tax Rate	40%	Combined Federal/State Corporate Income Tax Rate.
Evaluation Period	20 years	Base Case Assumption.
Depreciation Schedule:		
Conventionals	15 year	MACRS
Wind	5 year	MACRS
Nominal Interest Rate During Construction	10%	Base Case Assumption.
Dollar Year	2004	All costs are expressed in year 2004 dollars.

2.2 Power System Characteristics

2.2.1 ReEDS Regions

There are five types of regions used in the ReEDS model; these are:

1. Interconnects — There are three major interconnects in the United States: Eastern interconnect, Western interconnect, and ERCOT (Electric Reliability Council of Texas) interconnect. These are electrically asynchronous regions, isolated from each other except for a limited number of AC-DC-AC connections.

2. National Electric Reliability Council (NERC) Subregions — There are 13 NERC subregions used in ReEDS. Table 2 provides a listing of NERC region names and locations.

3. Regional Transmission Operators (RTOs) — There are 32 RTOs as shown in Figure 2.

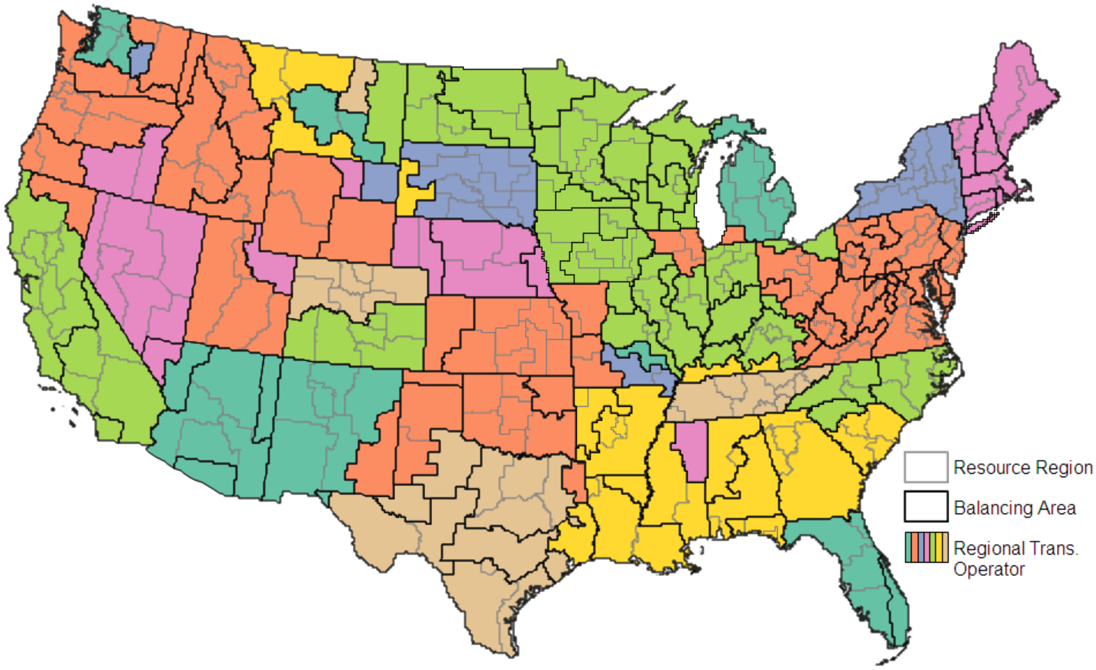

Figure 2: Regions used in ReEDS

4. Balancing Areas — There are 134 balancing areas.

5. Resource Regions — There are 356 resource regions.

Interconnects, NERC regions, RTOs, and balancing authorities are defined by various regulatory agencies (see Table 2 for a definition of NERC regions). Wind Resource Regions were created specifically for the ReEDS model. The regions have been selected using the following rules and criteria:

- Build up from counties (so that electric load can be determined for each wind supply/demand region based on county population).
- Avoid crossing state boundaries (so that state-level policies can be modeled).
- Conform to balancing areas as much as possible (to better capture the competition between wind and other generators).
- Separate concentrations of wind and solar resource from load centers where possible (so that the distance from a wind resource to a load center can be better approximated).
- Conform to NERC region/subregion boundaries (so that the results are comparable to results produced by integrating models that use the NERC regions/subregions).

A detailed map with all resource regions and balancing authorities is provided in Figure 2.

The need for multiple levels of geographical resolution is based on several different components of the ReEDS model. For example, load growth rates are based on data from the NERC region level, while wind-generator performance is modeled at the wind-resource region level. The use of these various regions is discussed in further detail in Section 3.

Table 2: NERC Regions Used in ReEDS

Number	Abbreviation	Region Name
1	ECAR	East Central Area Reliability Coordination Agreement
2	ERCOT	Electric Reliability Council of Texas
3	MAAC	Mid-Atlantic Area Council
4	MAIN	Mid-America Interconnected Network
5	MAPP	Mid-Continent Area Power Pool
6	NY	New York
7	NE	New England
8	FRCC	Florida Reliability Coordinating Council
9	SERC	Southeast Reliability Council
10	SPP	Southwest Power Pool
11	NWP	Northwest
12	RA	Rocky Mountain Area
13	CNV	California/Nevada

Note: NERC regions in ReEDS are based on the pre-2006 regional definitions defined by the EIA (2009c). In January 2006, NERC regions were redefined. The EIA has not incorporated these changes through publication of AEO 2009; therefore, ReEDS will continue to use pre-2006 definitions until the EIA modifies its data. Similarly, some of the recent changes to balancing area boundaries (now referred to as balancing authorities) are not yet reflected in ReEDS (e.g. the formation of the Texas Regional Transmission Organization) but will be when the NERC regions are updated.

2.2.2 Electric System Loads

Loads are defined by region and by time-slice. ReEDS meets both the energy requirement and the power requirement for each of the 134 balancing areas. Load requirements are set for each balancing authority in each of 16 time-slices, for each year modeled by ReEDS. Table 3 defines these time-slices. The months corresponding to each season are as follows: Summer = {June, July, August}, Fall = {September, October}, Winter = {November, December, January, February}, Spring = {March, April, May}.

Table 3: ReEDS Demand Time-Slice Definitions

Slice Name	Hours Per Year	Season	Time Period
H1	736	Summer	10PM-6AM
H2	644	Summer	6AM-1PM
H3	328	Summer	1PM-5PM
H4	460	Summer	5PM-10PM
H5	488	Fall	10PM-6AM
H6	427	Fall	6AM-1PM
H7	244	Fall	1PM-5PM
H8	305	Fall	5PM-10PM
H9	960	Winter	10PM-6AM
H10	840	Winter	6AM-1PM
H11	480	Winter	1PM-5PM
H12	600	Winter	5PM-10PM
H13	736	Spring	10PM-6AM
H14	1104	Spring	6AM-1PM, 5PM-10PM
H15	368	Spring	1PM-5PM
H16	40	Summer	Superpeak

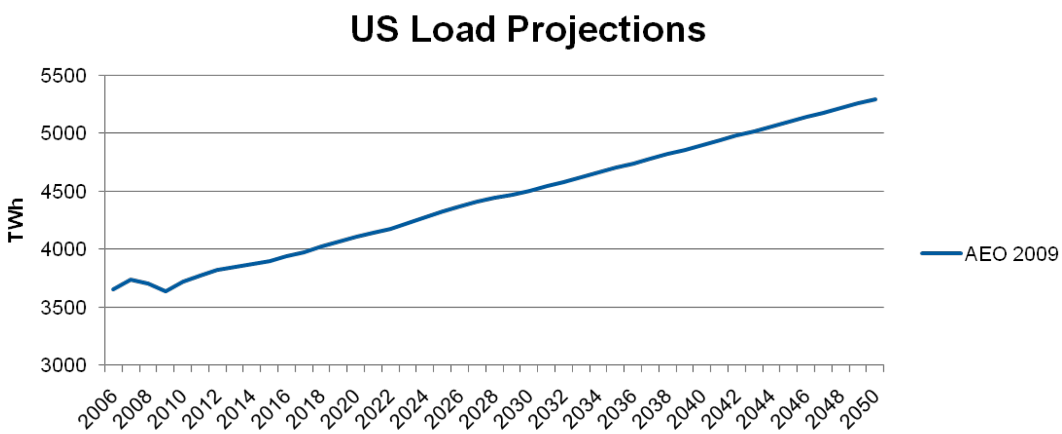

Figure 3: National projected load from AEO 2009 reference case with linear extrapolation to 2050

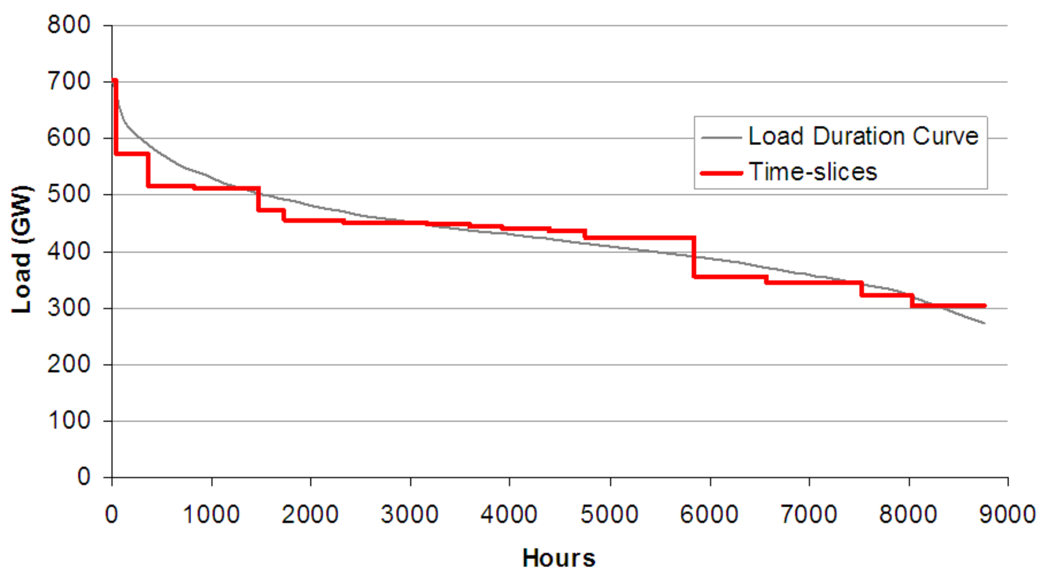

Figure 4: National Load Duration Curve in ReEDS

The electric load in 2006 for each balancing authority and time-slice is derived from the Platts Energy Markets database (2006). The load growth rates by NERC region for all years after 2006 are derived from the reference case in the updated Annual Energy Outlook (EIA 2009). Since AEO 2009 load projections only extend until 2030, the projected load for 2031 to 2050 are derived from a linear extrapolation of the AEO projected load from 2020 to 2030. Figure 3 shows the national projected load from AEO 2009 with extrapolations to 2050.

Figure 4 illustrates the ReEDS load duration curve for the entire United States for a sample year, illustrating the 16 load time-slices. As a reference, the smoother U.S. coincident load duration curve is depicted in the figure as well. The aggregated data for the United States that are shown in Figure 4 are not used directly in ReEDS, as the energy requirement is met in each balancing area. This curve does, however, give a general idea of the ReEDS energy requirement.

The actual load to be met in ReEDS differs from the projected loads described above due to demand elasticities based on electricity price. (see Appendix C). Table 4 contains the first ReEDS investment year (2006) for each NERC subregion.

Table 4: Base Load and Load Growth in the ReEDS Base Case

NERC Region/Subregion		2006 Load (TWh/year)[a]	Reserve Margin (%)[b]
1	ECAR	531	12
2	ERCOT	291	15
3	MAAC	265	15
4	MAIN	262	12
5	MAPP	153	12
6	NY	143	18
7	NE	125	15
8	FL	215	15
9	SERC	824	13
10	SPP	191	12
11	NWP	217	08
12	RA	177	14
13	CNV	258	13

[a](EIA 2009), [c](PA Consulting Group 2004)

2.2.3 Capacity Requirements

For each RTO, ReEDS requires sufficient capacity to meet the peak instantaneous demand throughout the course of the year, plus a peak reserve margin. The reserve margin requirement can be met by any generator type, although the generator must have the appropriate capacity value. In the cases of wind and solar power, the actual capacity value is a minority fraction of the nameplate capacity; section D describes how this capacity value fraction is calculated for generators with variable resources like wind and solar.

The peak reserve margin for each RTO is provided in Table 4. The reserve margin frction is ramped from its actual value in 2006 to the 2010 requirement, and is maintained at the 2010 level thereafter. It is assumed that energy growth and peak demand grow at the same rate, and the load shape stays constant from one year to the next.

2.3 Wind

2.3.1 Wind Resource Definition

Wind power classes are defined as in Table 5. Wind power density and speed are not used explicitly in ReEDS. Instead, the different classes of wind power are distinguished in ReEDS through the resource levels, capacity factors, turbine costs, etc., all of which are discussed below.

Table 5: Classes of Wind Power Density

Wind Power Class	Wind Power Density (W/m^2)	Speed (m/s)
3	300-400	6.4-7.0
4	400-500	7.0-7.5
5	500-600	7.5-8.0
6	600-800	8.0-8.8
7	>800	>8.8

Note: Wind speed measured at 50 m above ground level
Source: Elliott and Schwartz (1993)

A map of wind resource by class is shown in figure 5. The supply curve used in ReEDS includes both onshore and offshore wind resources and distinguishes between shallow and deep offshore wind turbines. Shallow-water turbines are assumed to have lower initial costs than deep offshore turbines, because they employ a solid tower with an ocean bottom pier; while deep-water turbines are assumed to be mounted on floating platforms tethered to the ocean floor.

These different classes and types of wind have different costs and performance characteristics. Generally, the higher wind class sites (i.e. Class 7) are the preferred sites. However, in selecting the installation sites, ReEDS considers not only the resource quality, but also includes factors such as transmission availability, costs, and losses; correlation of the wind output with neighboring sites; environmental exclusions; site slope; and population density. As a result, in any given period, the wind turbines installed will be at a mix of sites with different wind resource classifications.

2.3.2 Wind Resource Data

The wind-resource dataset for the ReEDS model is based on separate sets of supply curves for each of onshore, shallow offshore, and deep offshore. This regional wind-resource dataset is generated by multiplying the total available area of a particular wind resource by an assumed wind-farm density of 5 MW/km^2 (NREL 2006). The amount of land available for each class is based on a dataset for each of the 356 resource regions for onshore, shallow offshore, and deep offshore. The resource data is derived from a variety of sources outlined in Table 6 for onshore wind and Table 8 for offshore wind. The wind resouce data are for 50m hub-height.

The wind-resource availability in ReEDS includes many land exclusions described in Table 7.

2.3.3 Wind Technology Cost and Performance

Black & Veatch analysts developed wind technology cost and performance projections for the model in consultation with the American Wind Energy Association's (AWEA) industry experts (O'Connell and Pletka 2007). Costs for turbines, towers, foundations, installation, profit, and interconnection fees are included. Capital costs are based on an average installed capital cost

Table 6: Data Source for Wind Resource

State	Data Source	State	Data Source
Arizona	2003, N/AWST	Nebraska[a]	2005, N/AWST
Alabama	1987, PNL	Nevada	2003, N/AWST
Arkansas	2006, N/AWST[p]	New Hampshire	2002, N/AWST
California	2003, N/AWST	New Jersey	2003, N/AWST
Colorado	2003, N/AWST	New Mexico	2003, N/AWST
Connecticut	2002, N/AWST	New York[a]	2004, N/AWST
Delaware	2003, N/AWST	North Carolina	2003, N/AWST
Florida	1987, PNL	North Dakota	2000 NREL
Georgia	2006, AWST	Ohio[a]	2004, N/AWST
Idaho	2002, N/AWST	Oklahoma[a]	2002, OTH
Illinois	2001, NREL	Oregon	2002, N/AWST
Indiana[a]	2004, N/AWST	Pennsylvania[a]	2003, N/AWST
Iowa	1997, OTH	Rhode Island	2002, N/AWST
Kansas	2004, OTH	South Carolina	2005, AWST
Kentucky	1987, PNL	South Dakota	2000 NREL
Louisiana	1987, PNL	Tennessee	1987, PNL
Maine	2002, N/AWST	Texas	2004, OTH/2000, NREL
Maryland	2003, N/AWST	Utah	2003, N/AWST
Massachusetts	2002, N/AWST	Vermont	2002, N/AWST
Michigan[a]	2005, N/AWST	Virginia	2003, N/AWST
Minnesota	2006, OTH	Washington	2002, N/AWST
Mississippi	1987, PNL	West Virginia	2003, N/AWST
Missouri[a]	2004, N/AWST	Wisconsin	2003, OTH
Montana	2002, N/AWST	Wyoming	2002, N/AWST

Notes on Sources:
PNL data resolution is 1/4 degree of latitude by 1/3 degree of longitude, each cell has a terrain exposure percent (5% for ridgecrest to 90% for plains) to define base resource area in each cell. Ridgecrest areas have 10% of the area assigned to the next higher power class. (PNL 1987)
NREL data was generated with the WRAMS model, and does not account for surface roughness. Resolution is 1 km. Texas includes the Texas mesas study area updated by NREL using WRAMS.
N/AWST data was generated by AWS TrueWind and validated by NREL. Resolution is 400 m for the northwest states (WA, OR, ID, MT, and WY) and 200 m everywhere else. These data consider surface roughness in their estimates.
N/AWST[p] data was generated by AWS TrueWind and will be validated by NREL. Data used is preliminary.
OTH data from other sources. The methods, resolution, and assumptions vary. These results have not been validated by NREL For most states, the data was taken at face value. However, some datasets were not available as 50 m power density. In those cases, assumptions were made to adjust the data to 50 m power density.
[a] In these states, the class 2, 3 and 4 wind power class estimates were adjusted upwards by 1/2 power class to better represent the likely wind resource at wind turbine height. For Nebraska, only the portion of the state east of 102 degrees longitude was adjusted.

Table 7: Wind-Resource Exclusion Database — Standard Version, January 2004

Criteria for Defining Available Windy Land (numbered in the order they are applied):

Environmental Criteria	Data/Comments:
2. 100% exclusion of National Park Service and Fish and Wildlife Service managed lands	USGS Federal and Indian Lands shapefile, Jan 2005
3. 100% exclusion of federal lands designated as park, wilderness, wilderness study area, national monument, national battlefield, recreation area, national conservation area, wildlife refuge, wildlife area, wild and scenic river or inventoried roadless area.	USGS Federal and Indian Lands shapefile, Jan 2005
4. 100% exclusion of state and private lands equivalent to criteria 2 and 3, where GIS data is available.	State/GAP land stewardship data management status, from Conservation Biology Institute Protected Lands database, 2004
8. 50% exclusion of remaining USDA Forest Service (FS) lands (incl. National Grasslands)*	USGS Federal and Indian Lands shapefile, Jan 2005
9. 50% exclusion of remaining Dept. of Defense lands*	USGS Federal and Indian Lands shapefile, Jan 2005
10 50% exclusion of state forest land, where GIS data is available*	State/GAP land stewardship data management status 2, from Conservation Biology Institute Protected Lands database, 2004

Land Use Criteria	Data/Comments:
5. 100% exclusion of airfields, urban, wetland and water areas.	USGS North America Land Use Land Cover (LULC), version 2.0, 1993; ESRI airports and airfields (2003)
11. 50% exclusion of non-ridgecrest forest*	Ridge-crest areas defined using a terrain definition script, overlaid with USGS LULC data screened for the forest categories.

Other Criteria	Data/Comments:
1. Exclude areas of slope > 20%	Derived from elevation data used in the wind resource model.
6. 100% exclude 3 km surrounding criteria 2-5 (except water)	Merged datasets and buffer 3 km
7. Exclude resource areas that do not meet a density of 5 km^2 of class 3 or better resource within the surrounding 100 km2 area.	Focalsum function of class 3+ areas (not applied to 1987 PNL resource data)

* 50% exclusions are not cumulative; i.e. if an area is non-ridgecrest forest on FS land, it is just excluded at the 50% level one time.

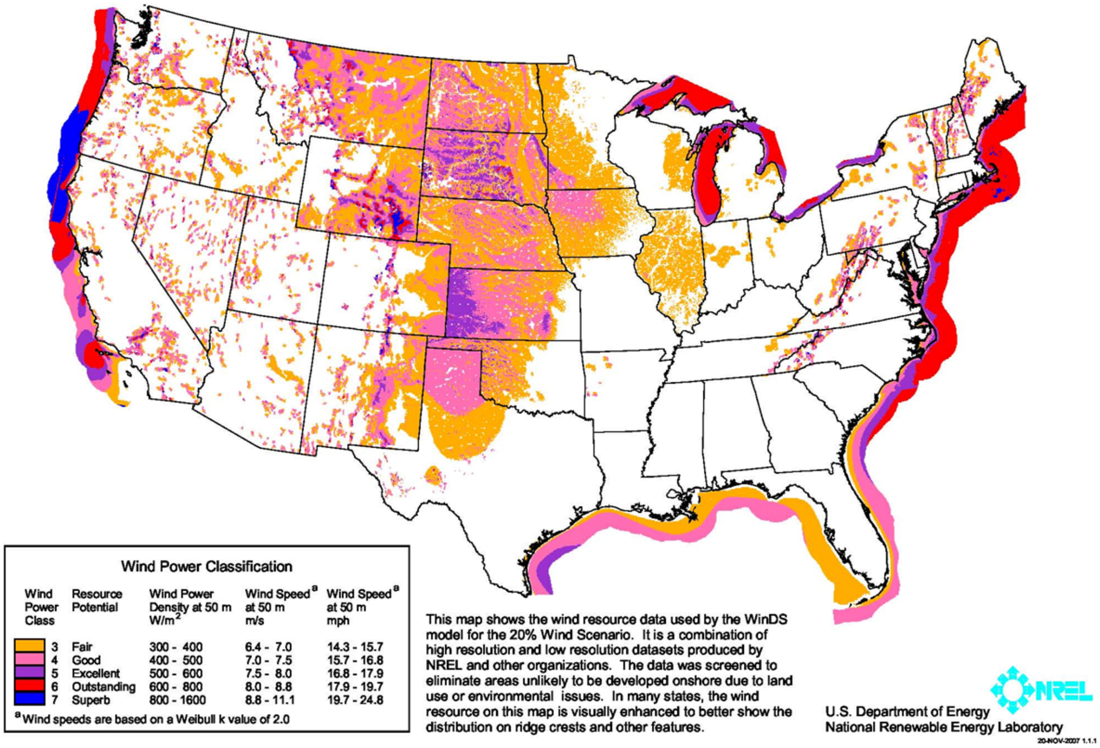

Figure 5: Wind Resource in ReEDS

of \$1,775 per kilowatt (kW) in 2007, which reduces to \$1,570/kW in 2004\$ after adjusting for inflation and removing the construction financing charge. Additional costs reflecting terrain slope and regional population density are described later in this section.

Technology development is projected to reduce wind capital costs by 10% by 2030. Black & Veatch used historical capacity factor data to create a logarithmic best-fit line, which is then applied to each wind power class to project future performance improvements.[1] The capacity factors in Table 9 are annual averages for each class. Seasonal and diurnal wind data were exploited to develop seasonal and diurnal capacity factor corrections for each region; allowing the model to better address the variability of wind. Variable and fixed operations and maintenance (O&M) costs represent an average of recent project costs according to Black & Veatch's experience. Approximately 50% of variable O&M cost is the turbine warranty. These costs are expected to decline as turbine reliability improves and the scale of wind turbines increases. Other variable O&M expenses are tied to labor rates, royalties, and other costs that are expected to be stable. Fixed O&M costs, including insurance, property taxes, site maintenance, and legal fees, are projected to stay the same because they are not affected by technology improvements. Table 9 lists cost and performance projections for land-based wind systems (O'Connell and Pletka 2007).

Tables 10 and 11 lists cost and performance projections prepared by Black & Veatch for shallow and deep offshore wind technology ("shallow" denotes in water shallower than 30 m). Capital costs for 2005 were based on publicly available cost data for European offshore wind farms. Capital costs are assumed to decline 12.5% as a result of technology development and a maturing market. The capacity factor projection, which is based on the logarithmic best-fit lines

[1] Capacity factors for 2005 fit to actual data. For the higher wind power classes (6 and 7), however, limited data are available for operating plants, so capacity factors were extrapolated from the linear relationships between wind classes.

Table 8: Data Source for Offshore Wind Resource

State	Data Source	State	Data Source
Alabama	2006, NREL3	Mississippi	2006, NREL3
California	2003, NREL1	New Hampshire	2002, NREL1
Connecticut	2002, NREL1	New Jersey	2003, NREL1
Delaware	2003, NREL1	New York	2003, NREL1
Florida	2006, NREL3	North Carolina	2003, NREL1
Georgia	2006, NREL3	Ohio	2006, NREL2
Illinois	2006, NREL2	Oregon	2002, NREL1
Indiana	2006, NREL2	Pennsylvania	2006, NREL2
Louisiana	2006, NREL3	Rhode Island	2002, NREL1
Maine	2002, NREL1	South Carolina	2006, NREL3
Maryland	2003, NREL1	Texas	2006, NREL3
Massachusetts	2003, NREL1	Virginia	2003, NREL1
Michigan	2006, NREL2	Washington	2002, NREL1
Minnesota	2006, NREL2	Wisconsin	2006, NREL2

Notes on Sources: All data from NREL, different methods detailed below
NREL1: Validated near-shore data was supplemented with offshore resource data from earlier, preliminary runs which extended further from shore. In most cases, this still did not fill the modeling area of interest of 50 nautical miles from shore. The resource estimates were extended linearly to obtain full coverage at 50 nautical miles with little or no change in spatial pattern.
NREL2: Similar to NREL1, but available resource data estimates and areas not covered by validated and preliminary data were evaluated by NREL meteorologists to establish a best estimate of resource distribution based on expert knowledge and available measured/modeled data sources.
NREL3: No validated resource estimates existed to provide a baseline. NREL meteorologists generated an initial best estimate of resource distribution to be used in the model, based on expert knowledge and available measured/modeled data sources.

generated for land-based turbines, was increased 15% to account for larger rotor diameters and reduced wind turbulence over the ocean. By 2030 this adjustment factor is reduced to 5% as land-based development allows larger turbines to be used in turbulent environments. O&M costs are assumed to be three times those of land-based turbines (Musial and Butterfield 2004) with a learning rate commensurate to that projected by the U.S. Department of Energy (DOE; NREL 2006).

A number of adjustments, including financing, interest during construction, terrain slope, population density, and rapid growth were applied to the capital cost. Although financing has not been treated explicitly, it is assumed to be captured by the weighted cost of capital (real discount rate) of 8.5%. Additionally, there is a user option to implement a "learning factor" applicable to wind costs and capacity factors. Specifically, for each doubling of wind capacity, there is an 8% improvement applied to capital costs and capacity factors. (Learning-based improvements on the installation cost depend on domestic wind capacity while the costs of the turbines themselves benefit from the expansion of capacity worldwide.)

A slope penalty that increases the installation cost by 2.5% per degree of terrain slope was used to represent expected costs associated with installations on mesas or ridge crests. (Costs associated with installation represent 25% of the capital cost.) Wiser and Bolinger (2007) present regional variations in installed capital cost for projects constructed in 2006. Applying a multiplier related to population density within each of the 356 resource regions results in regional variations similar to that observed in data. An additional 20% is applied to the base capital cost in New England to reflect observed capital cost variations. Slope and population density penalties have been applied to the capital cost listed in Tables 9-11 within the model to represent topographical and regional variations across the United States.

There are also "excessive growth" penalties applied to wind costs if the demand for new wind capacity significantly exceeds that supplied in earlier years. Specifically, if new wind

Table 9: Onshore Wind Cost and Performance Projections

Resource Class	Install Year	Capacity Factor	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
3	2005	0.320	1570	10.95	6.66
3	2010	0.360	1570	10.95	5.19
3	2020	0.380	1490	10.95	4.41
3	2030	0.380	1413	10.95	4.16
3	2040	0.380	1413	10.95	4.16
3	2050	0.380	1413	10.95	4.16
4	2005	0.360	1570	10.95	6.66
4	2010	0.390	1570	10.95	5.19
4	2020	0.420	1490	10.95	4.41
4	2030	0.430	1413	10.95	4.16
4	2040	0.430	1413	10.95	4.16
4	2050	0.430	1413	10.95	4.16
5	2005	0.401	1570	10.95	6.66
5	2010	0.430	1570	10.95	5.19
5	2020	0.450	1490	10.95	4.41
5	2030	0.460	1413	10.95	4.16
5	2040	0.460	1413	10.95	4.16
5	2050	0.460	1413	10.95	4.16
6	2005	0.440	1570	10.95	6.66
6	2010	0.460	1570	10.95	5.19
6	2020	0.480	1490	10.95	4.41
6	2030	0.490	1413	10.95	4.16
6	2040	0.490	1413	10.95	4.16
6	2050	0.490	1413	10.95	4.16
7	2005	0.470	1570	10.95	6.66
7	2010	0.500	1570	10.95	5.19
7	2020	0.520	1490	10.95	4.41
7	2030	0.530	1413	10.95	4.16
7	2040	0.530	1413	10.95	4.16
7	2050	0.530	1413	10.95	4.16

installations are more than 20% greater than those of the preceding year, there is a 1% increase in capital cost for each 1% growth above 20% per year (EIA 2004).

Table 10: Shallow Offshore Turbines

Resource Class	Install Year	Capacity Factor	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
3	2005	0.340	2284	14.28	20.0
3	2010	0.370	2186	14.28	17.1
3	2020	0.390	2053	14.28	13.3
3	2030	0.400	2009	14.28	10.5
3	2040	0.420	2009	14.28	10.5
3	2050	0.420	2009	14.28	13.6
4	2005	0.380	2284	14.28	20.0
4	2010	0.410	2186	14.28	17.1
4	2020	0.440	2053	14.28	13.3
4	2030	0.450	2009	14.28	10.5
4	2040	0.450	2009	14.28	10.5
4	2050	0.450	2009	14.28	13.6
5	2005	0.420	2284	14.28	20.0
5	2010	0.450	2186	14.28	17.1
5	2020	0.470	2053	14.28	13.3
5	2030	0.480	2009	14.28	10.5
5	2040	0.480	2009	14.28	10.5
5	2050	0.480	2009	14.28	13.6
6	2005	0.460	2284	14.28	20.0
6	2010	0.480	2186	14.28	17.1
6	2020	0.510	2053	14.28	13.3
6	2030	0.510	2009	14.28	10.5
6	2040	0.510	2009	14.28	10.5
6	2050	0.510	2009	14.28	13.6
7	2005	0.500	2284	14.28	20.0
7	2010	0.520	2186	14.28	17.1
7	2020	0.550	2053	14.28	13.3
7	2030	0.550	2009	14.28	10.5
7	2040	0.550	2009	14.28	10.5
7	2050	0.550	2009	14.28	13.6

Table 11: Deep Offshore Turbines

Resource Class	Install Year	Capacity Factor	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
3	2005	0.380	3046	14.28	22.8
3	2010	0.380	3046	14.28	22.8
3	2020	0.390	2665	14.28	20.0
3	2030	0.400	2475	14.28	15.2
3	2040	0.400	2284	14.28	13.3
3	2050	0.400	2284	14.28	13.3
4	2005	0.430	3046	14.28	22.8
4	2010	0.430	3046	14.28	22.8
4	2020	0.440	2665	14.28	20.0
4	2030	0.450	2475	14.28	15.2
4	2040	0.450	2284	14.28	13.3
4	2050	0.450	2284	14.28	13.3
5	2005	0.460	3046	14.28	22.8
5	2010	0.460	3046	14.28	22.8
5	2020	0.470	2665	14.28	20.0
5	2030	0.480	2475	14.28	15.2
5	2040	0.480	2284	14.28	13.3
5	2050	0.480	2284	14.28	13.3
6	2005	0.500	3046	14.28	22.8
6	2010	0.500	3046	14.28	22.8
6	2020	0.510	2665	14.28	20.0
6	2030	0.510	2475	14.28	15.2
6	2040	0.510	2284	14.28	13.3
6	2050	0.510	2284	14.28	13.3
7	2005	0.540	3046	14.28	22.8
7	2010	0.540	3046	14.28	22.8
7	2020	0.550	2665	14.28	20.0
7	2030	0.550	2475	14.28	15.2
7	2040	0.550	2284	14.28	13.3
7	2050	0.550	2284	14.28	13.3

2.4 Solar

2.4.1 CSP Resource Definition

For CSP, a certain level of average annual radiation is needed before the resource can be considered viable. In the United States, those viable resource areas are located primarily within the southwestern states. Therefore, in the ReEDS model, this subset of regions is the area in which CSP solar plants are allowed. This reduction in the number of regions significantly reduces the run-time requirements of ReEDS, as well as the amount of solar GIS inputs.

Similar to the model's breakdown of wind resource into five standard classes, the solar resource appropriate for CSP systems has also been divided into five classes that are defined by the annual average direct normal radiation. The breakdown by class is oulined in Table 12.

Table 12: Classes of Wind Power Density

CSP Power Class	Solar Power Density (kWh/m^2/day)
1	6.75-6.99
2	7.00-7.24
3	7.25-7.49
4	7.50-7.74
5	7.75-8.06

Additionally, a variety of exclusions are applied to the solar resource if the slope exceeds 1%, average annual radiation is less than 6.75 kWh/m^2/day (the input is currently being expanded to include solar resource down to 5 kWh/m^2/day), the area is a major urban or wetland area or a protected federal land. If the remaining resource lands are less than 5 contiguous sq. km, they are excluded. Figure 6 maps the location of the solar resource that is used within ReEDS.

2.4.2 CSP Technology Cost and Performance

As of November 2008, CSP in ReEDS consists of a single technology (parabolic trough Rankine cycle, similar to the SEGS plants installed in California) with a preselected thermal storage capacity (six hours of thermal storage). These factors, combined with an assumed scale of 100 MW plant size, determine the initial cost and performance characteristics.

The storage assumption greatly simplifies the treatment of resource variability. Because the plant is assumed to be dispatchable, the capacity value for the plant is assumed to be equal to the capacity factor during the summer peak load period, which is essentially the nameplate capacity. Additionally, no operating reserve is necessary for this plant, and surplus is assumed to be negligible due to the alignment of the solar resource and load. (In the future, there may be an option to remove the storage assumption for CSP.)

Excelergy was also used outside of ReEDS to determine the performance of the assumed system for a variety of locations, representing all five solar classes. For each location, the hourly output of *Excelergy* was aggregated into the 16 time-slices within ReEDS to determine the average capacity factor for each time-slice of the year, for each solar class (Table 13). For the Base Case, it is conservatively assumed that these capacity factors (i.e. solar plant performance) were unchanged in the future. In reality, it is expected that these would improve through R&D and shared operational improvements.

Based on the 2005 DOE Solar Program Multiyear Technology Plan (EERE 2005), we assume that 54% of the cost improvements projected by DOE will occur through R&D (Table 13). In addition to the improvements over time shown in Table 13, ReEDS also allows for user inputted "learning" improvements in the cost values. For each doubling of installed worldwide CSP

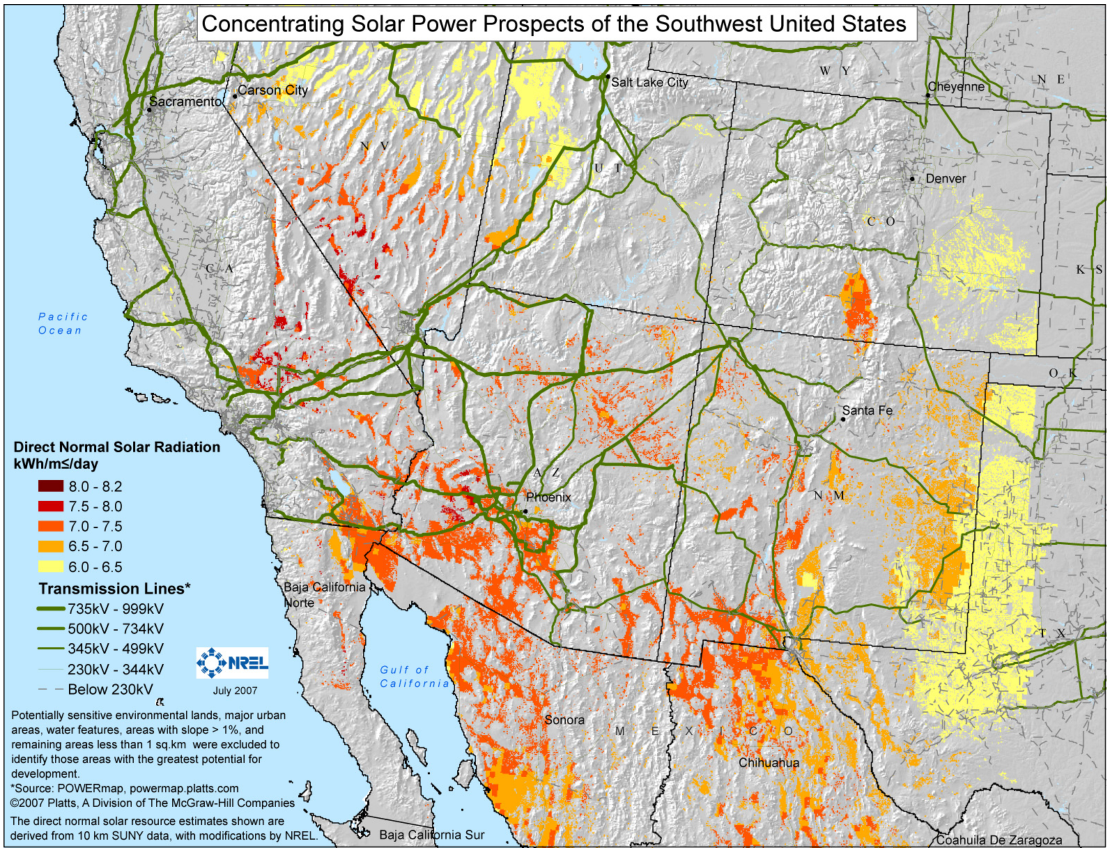

Figure 6: Solar Resource in ReEDS

capacity (a scenario of CSP installations outside the United States reaching 120 GW by 2040 is input), there is an 8% reduction in costs.

2.4.3 Photovoltaics

A national projection of distributed photovoltaic (PV) capacity expansion by NERC region is exogenously input into ReEDS. Currently, there are two types of projections, one for the base case and another for high renewable penetration (such as national RPS or carbon cap/tax) cases. The national distributed PV projection for high renewable penetration cases was obtained from the "Cap Only" case of the Climate 2030 Blueprint from the Union of Concerned Scientists.

Though the distributed PV installed capacity projection is exogenously input by NERC region, ReEDS determines the spatial distribution of PV installations within the NERC regions. In other words, distributed PV competes at the PCA level based on the availability and quality of the solar resource, local incentives, and the mix of generators serving the PCA. Table 14 shows the cost of distributed PV currently input in ReEDS.

Annual capacity factors of distributed PV for each PcA were based on the regional availability of the solar resource. These capacity factors were then corrected for each ReEDS timeslice, using the seasonal-diurnal power output profiles from a random selection of sites around the country oriented toward the south at a 25 degree tilt from the horizontal. (The data used in the calculation was from NREL.)

Currently ReEDS cannot build central photovoltaic plants. However, this capability will be put into the model in the near future.

Table 13: CSP Cost and Performance Projections

Resource Class	Install Year	Capacity Factor	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
1	2005	0.4088	5850	55.72	0.1
1	2010	0.4088	5572	51.07	0.1
1	2020	0.4088	4179	44.57	0.1
1	2030	0.4088	4179	44.57	0.1
1	2040	0.4088	4179	44.57	0.1
1	2050	0.4088	4179	44.57	0.1
2	2005	0.4132	5850	55.72	0.1
2	2010	0.4132	5572	51.07	0.1
2	2020	0.4132	4179	44.57	0.1
2	2030	0.4132	4179	44.57	0.1
2	2040	0.4132	4179	44.57	0.1
2	2050	0.4132	4179	44.57	0.1
3	2005	0.4274	5850	55.72	0.1
3	2010	0.4274	5572	51.07	0.1
3	2020	0.4274	4179	44.57	0.1
3	2030	0.4274	4179	44.57	0.1
3	2040	0.4274	4179	44.57	0.1
3	2050	0.4274	4179	44.57	0.1
4	2005	0.4415	5850	55.72	0.1
4	2010	0.4415	5572	51.07	0.1
4	2020	0.4415	4179	44.57	0.1
4	2030	0.4415	4179	44.57	0.1
4	2040	0.4415	4179	44.57	0.1
4	2050	0.4415	4179	44.57	0.1
5	2005	0.4570	5850	55.72	0.1
5	2010	0.4570	5572	51.07	0.1
5	2020	0.4570	4179	44.57	0.1
5	2030	0.4570	4179	44.57	0.1
5	2040	0.4570	4179	44.57	0.1
5	2050	0.4570	4179	44.57	0.1

Table 14: Distributed PV Cost and Performance Projections

Install Year	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Heat Rate MMbtu/MWh
2005	5000	70.00	0.0	10
2010	3480	22.00	0.0	10
2020	2100	7.50	0.0	10
2030	1512	5.40	0.0	10
2040	1474	5.27	0.0	10
2050	1436	5.13	0.0	10

2.5 Conventional Generation

2.5.1 Generator Types

Available generator types that may be built are based on the most likely types as determined by the DOE Energy Information Administration (EIA 2009a). The generator types, with shorthand notation, are as follows:

- Conventional hydropower, hydraulic turbine — Hydro
- Natural gas combustion turbine — Gas-CT
- Combined cycle gas turbine — Gas-CC
- Combined cycle gas turbine with carbon capture and sequestration (CCS) — Gas-CCS
- Conventional pulverized coal steam plant (no SO_2 scrubber) — CoalOldUns
- Conventional pulverized coal steam plant (with SO_2 scrubber) — CoalOldScr
- Conventional pulverized coal steam plant (with SO_2 scrubber and biomass cofiring) — CofireOld
- Advanced supercritical coal steam plant (with SO_2 and NO_x controls) — CoalNew
- Advanced supercritical coal steam plant (with biomass cofiring) — CofireNew
- Integrated gasification combined cycle (IGCC) coal — Coal-IGCC
- IGCC with carbon capture and sequestration (CCS) — Coal-CCS
- Oil/gas steam turbine — OGS
- Nuclear plant — Nuclear
- Municipal solid waste/landfill gas plant — MSW
- Biomass gasification plant — Biomass
- Geothermal plant — Geothermal

Several adjustments are applied to the capital cost, including financing, interest during construction, learning, and rapid growth. In the Base Case, financing is not treated explicitly[2]. It is assumed to be captured by the real discount rate of 8.5%, which is a weighted cost of capital. As the capital costs of conventional technologies are acquired from Black & Veatch and have, already been adjusted for learning, no additional learning is assumed for these technologies in the Base Case.

Interest during construction can increase the effective capital cost for each technology. Table 15 indicates the construction time and schedule for each conventional technology. Lifetimes for conventional generating facilities are used for retirement calculations, not as a financial evaluation period (the evaluation period is 20 years for all technologies).

ReEDS considers the outage rate when determining the net capacity available for generation described among the calculations in Section 3.4.4, and in determining the capacity value of each technology. Planned outages are assumed to occur in all seasons except the summer. Table 16 provides the outage rate for each conventional technology (NERC 2008).

Emission rates are estimated for SO_2, NO_x, Mercury (Hg), and CO_2. Table 16 provides the input emission rates (lbs/MMBtu of input fuel) for plants that use combustible fuel. Output emission rates (lb/MWh) may be calculated by multiplying input emission rate by heat rate.

Sources and Notes on Emissions:

[2]A full range of financing options are built into the model as detailed in Appendix F.

Table 15: Construction Parameters for Conventional Generation

Plant Type	New builds in ReEDS?	Construction Time (years)	Construction Schedule (Fraction of cost in each year)						Lifetime (years)
Hydro	No	NA	-	-	-	-	-	-	100
Gas-CT	Yes	3	0.8	0.1	0.1	-	-	-	30
Gas-CC	Yes	3	0.5	0.4	0.1	-	-	-	30
Gas-CCS	Yes	3	0.5	0.4	0.1	-	-	-	30
CoalOldUns	No	NA	-	-	-	-	-	-	60
CoalOldScr	No	NA	-	-	-	-	-	-	60
CofireOld	No	NA	-	-	-	-	-	-	60
CoalNew	Yes	4	0.4	0.3	0.2	0.1	-	-	60
CofireNew	Yes	4	0.4	0.3	0.2	0.1	-	-	60
Coal-IGCC	Yes	4	0.4	0.3	0.2	0.1	-	-	60
Coal-CCS	Yes	4	0.4	0.3	0.2	0.1	-	-	60
OGS	No	NA	-	-	-	-	-	-	50
Nuclear	Yes	6	0.1	0.2	0.2	0.2	0.2	0.1	30
MSW	No	NA	-	-	-	-	-	-	30
Biomass	Yes	4	0.4	0.3	0.2	0.1	-	-	45
Geothermal	Yes	4	0.4	0.3	0.2	0.1	-	-	20

Table 16: Performance Parameters for Conventional Generation

Plant Type	Forced Outage Rate (%)	Planned Outage Rate (%)	Emissions Rates (lbs/MMBtu fuel input)			
			SO_2	NO_x	Hg	CO_2
Hydro	4.44	9.40	0	0	0	0
Gas-CT	8.14	4.23	6e-4	0.08	0	121.83
Gas-CC	6.73	6.53	6e-4	0.02	0	121.83
Gas-CCS	6.73	6.53	6e-4	0.02	0	12.18
CoalOldUns	6.56	8.09	1.57	.448	4.6e-6	204.12
CoalOldScr	6.56	8.09	.236	.448	4.6e-6	204.12
CofireOld	6.56	8.09	.236	.448	4.6e-6	204.12
CoalNew	6.56	8.09	.157	.02	4.6e-6	204.12
CofireNew	6.56	8.09	.157	.02	4.6e-6	204.12
Coal-IGCC	6.56	8.09	.0184	.02	4.6e-6	204.12
Coal-CCS	6.56	8.09	.0184	.02	4.6e-6	20.41
OGS	10.36	11.57	0.026	0.1	0	121.83
Nuclear	3.88	8.05	0	0	0	0
MSW	5.0	5.0	0	0	0	0
Biomass	5.0	5.0	.08	0	0	0
Geothermal	0.65	2.36	0	0	0	0

SO_2: SO_2 emissions result from the oxidization of sulfur contained in the fuel. Natural gas emissions rates are from an EPA air pollution study (1996); SO_2 input emissions rate for coal is based on the sulfur content of the fuel, and the use of post-combustion controls. The "base" emissions rate for existing and new conventional coal plants is based on a national average sulfur content of 0.9 lbs/MMBtu (1.8 lb SO_2/MMBtu). ReEDS assumes the national average for "low sulfur" coal is 0.5 lbs SO_2/MMBtu from values based on national averages from AEO Assumptions (EIA 2006 - Table 73). Scrubber removal efficiency is assumed to be 90% for retrofits, 95% for new plants. (EPA 2006)

NO_x: NO_x emissions result from the oxidization of Nitrogen in the air. It is not a result of the type of fuel burned, but the combustion characteristics of the generator. NO_x emissions can be reduced through a large variety of combustion controls, or post combustion controls. NO_x emissions are not restricted in the ReEDS Base Case (see Section 2.8.1 on federal emissions standards). The emissions rates in Table 16 are national averages. (EPA 2005b)

Hg: Mercury is a trace constituent of coal. Mercury emissions are unrestricted in the ReEDS Base Case (see section on federal emissions standards). Emissions rates in Table 16 are averages and do not consider control technologies. (EPA 2005b)

CO_2: CO_2 emissions result from the oxidization of carbon in the fuel, and the emissions rate is based solely on fuel type, and therefore constant (per fuel input) for all plants burning the same fuel type. Natural gas emissions rates are from an EPA air pollution study (1996); CO_2 content for coal is based on the national average from AEO Assumptions (EIA 2006 - Table 73). Biofuels are assumed to be carbon neutral. Landfill gas is assumed to have zero carbon emissions, since the gas would be flared otherwise. CSP plants burn a small amount of natural gas, resulting in CO_2 emissions. CO_2 emissions are not constrained in the ReEDS Base Case.

2.5.2 Cost and Basic Performance

Values for capital cost, heat rate (efficiency), fixed O&M, and variable O&M for conventional technologies that can be added to the electric system are provided in Tables 17 and 18. Cost and performance values for natural gas, nuclear, and coal technologies are based on recent project costs according to Black & Veatch experience. Pulverized coal plants continue to operate in ReEDS, and SO_2 scrubbers can be added to unscrubbed coal plants for $200/kW. Oil/gas steam, and unscrubbed coal plants can not be added to the electric system, but those currently in operation are maintained until retired. ReEDS sites conventional generation technology in the balancing area that is closest to the load being served and does not require new transmission. California law prohibits building new coal plants or purchasing power from out-of-state coal plants. ReEDS approximates that by outlawing new coal plants in the state and by restricting coal generation in other western states to only what they themselves can consume.

Roughly accounting for construction times, capital costs for 2005, 2010, and 2015 are based on proposed engineering, procurement, and construction (EPC) estimates for plants that will be commissioned in 2010, 2015, and 2020. A wet scrubber is included in the EPC costs for new pulverized coal plants. Owners' costs of 20% for coal, nuclear, and combined-cycle gas plants and 10% for simple-cycle gas plants provide an "all-in" cost. These owners' costs are based on national averages and include transmission and interconnection, land, permitting, and other costs. As with wind systems, 20% is added to the capital cost of coal and nuclear builds in New England, representing siting difficulties.

2.5.3 Fuel Prices

Base fuel prices for natural gas and coal are derived from projections from the AEO 2009 report (EIA 2009 - Energy Prices by Sector and Source). These tables provide the prices in each census region, which are then assigned to a NERC subregion used in ReEDS. Prices in the AEO are

Table 17: Cost and Performance Characteristics for Conventional Generation I

Plant Type	Install Year	Capital Cost ($/kW)	Fixed O&M ($/MW-yr)	Variable O&M ($/MWh)	Heat Rate MMbtu/MWh
Hydro	2005	1320	12720	3.20	10.34
Hydro	2010	1320	12720	3.20	10.34
Hydro	2020	1320	12720	3.20	10.34
Hydro	2030	1320	12720	3.20	10.34
Hydro	2040	1320	12720	3.20	10.34
Hydro	2050	1320	12720	3.20	10.34
Gas-CT	2005	595	7329	11.42	11.56
Gas-CT	2010	595	7329	11.42	11.56
Gas-CT	2020	714	6282	2.67	8.9
Gas-CT	2030	714	6282	2.67	8.9
Gas-CT	2040	714	6282	2.67	8.9
Gas-CT	2050	714	6282	2.67	8.9
Gas-CC	2005	742	13706	2.86	6.87
Gas-CC	2010	742	13706	2.86	6.87
Gas-CC	2020	742	13706	2.86	6.87
Gas-CC	2030	742	13706	2.86	6.87
Gas-CC	2040	742	13706	2.86	6.87
Gas-CC	2050	742	13706	2.86	6.87
Gas-CCS	2005	1371	0	8.09	7.79
Gas-CCS	2010	1334	0	8.09	7.79
Gas-CCS	2020	1238	0	8.09	7.79
Gas-CCS	2030	1122	0	8.09	7.79
Gas-CCS	2040	1122	0	8.09	7.79
Gas-CCS	2050	1122	0	8.09	7.79
CoalOldUns	2005	1000	27156	4.35	10.00
CoalOldUns	2010	1000	27156	4.81	10.00
CoalOldUns	2020	1000	27156	5.86	10.00
CoalOldUns	2030	1000	27156	7.14	10.00
CoalOldUns	2040	1000	27156	8.71	10.00
CoalOldUns	2050	1000	27156	10.62	10.00
CoalOldScr	2005	1204	23410	3.75	10.00
CoalOldScr	2010	1204	23410	4.14	10.00
CoalOldScr	2020	1204	23410	5.05	10.00
CoalOldScr	2030	1204	23410	6.16	10.00
CoalOldScr	2040	1204	23410	7.51	10.00
CoalOldScr	2050	1204	23410	9.15	10.00
CofireOld	2005	1234	24460	3.75	10.00
CofireOld	2010	1234	24460	4.14	10.00
CofireOld	2020	1234	24460	5.05	10.00
CofireOld	2030	1234	24460	6.16	10.00
CofireOld	2040	1234	24460	7.51	10.00
CofireOld	2050	1234	24460	9.15	10.00
CoalNew	2005	2018	33599	1.62	9.47
CoalNew	2010	2075	33599	1.62	9.20
CoalNew	2020	2132	33599	1.62	9.00
CoalNew	2030	2132	33599	1.62	9.00
CoalNew	2040	2132	33599	1.62	9.00
CoalNew	2050	2132	33599	1.62	9.00

Table 18: Cost and Performance Characteristics for Conventional Generation II

Plant Type	Install Year	Capital Cost ($/kW)	Fixed O&M ($/MW-yr)	Variable O&M ($/MWh)	Heat Rate MMbtu/MWh
CofireNew	2005	2048	34649	1.62	9.47
CofireNew	2010	2105	34649	1.62	9.20
CofireNew	2020	2162	34649	1.62	9.00
CofireNew	2030	2162	34649	1.62	9.00
CofireNew	2040	2162	34649	1.62	9.00
CofireNew	2050	2162	34649	1.62	9.00
Coal-IGCC	2005	2617	36264	3.71	9.00
Coal-IGCC	2010	2703	36264	3.71	9.00
Coal-IGCC	2020	2703	36264	3.71	8.90
Coal-IGCC	2030	2703	36264	3.71	8.58
Coal-IGCC	2040	2703	36264	3.71	8.58
Coal-IGCC	2050	2703	36264	3.71	8.58
Coal-CCS	2005	3475	30000	8.09	9.70
Coal-CCS	2010	3412	30000	8.09	9.70
Coal-CCS	2020	3245	30000	8.09	9.59
Coal-CCS	2030	3043	30000	8.09	9.25
Coal-CCS	2040	3043	30000	8.09	9.25
Coal-CCS	2050	3043	30000	8.09	9.25
OGS	2005	396	25256	3.49	9.23
OGS	2010	390	25256	3.85	9.46
OGS	2020	370	25256	4.70	9.94
OGS	2030	351	25256	5.73	10.45
OGS	2040	351	25256	6.98	10.99
OGS	2050	351	25256	8.51	11.55
Nuclear	2005	3103	85663	0.48	10.40
Nuclear	2010	3016	85663	0.48	10.40
Nuclear	2020	2874	85663	0.48	10.40
Nuclear	2030	2801	85663	0.48	10.40
Nuclear	2040	2801	85663	0.48	10.40
Nuclear	2050	2801	85663	0.48	10.40
Geothermal	2005	3093	237950	0.00	32.32
Geothermal	2010	3093	237950	0.00	32.32
Geothermal	2020	3093	237950	0.00	32.32
Geothermal	2030	3093	237950	0.00	32.32
Geothermal	2040	3093	237950	0.00	32.32
Geothermal	2050	3093	237950	0.00	32.32
Biopower	2005	2617	66626	9.52	14.50
Biopower	2010	2617	66626	9.52	14.50
Biopower	2020	2617	66626	9.52	14.50
Biopower	2030	2617	66626	9.52	14.50
Biopower	2040	2617	66626	9.52	14.50
Biopower	2050	2617	66626	9.52	14.50
Landfill Gas	2005	3475	66626	9.52	15.63
Landfill Gas	2010	3326	66626	9.52	15.63
Landfill Gas	2020	3160	66626	9.52	15.63
Landfill Gas	2030	2957	66626	9.52	15.63
Landfill Gas	2040	2957	66626	9.52	15.63
Landfill Gas	2050	2957	66626	9.52	15.63

Notes: New nuclear plants may not be constructed before 2016. O&M costs do not include fuel. Heat rate is net heat rate (including internal plant loads). (O'Connell and Pletka 2007)

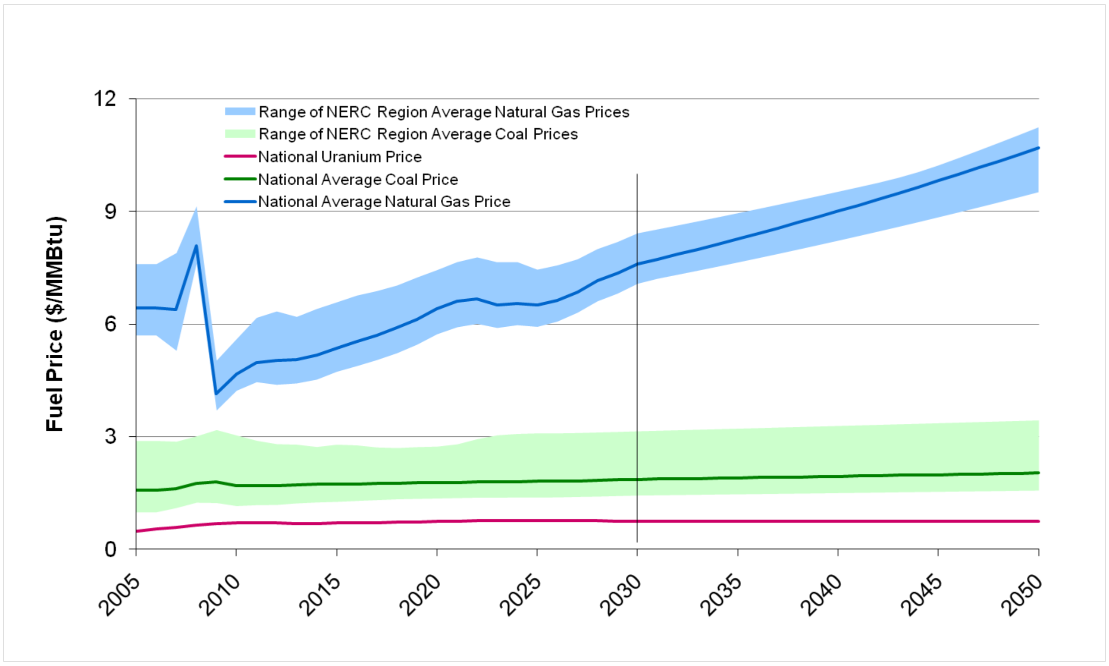

Figure 7: Base Fuel Price Trajectories

projected to 2030. Beyond 2030, ReEDS increases fuel prices at the same national annual average rate as projected by the AEO between 2020 and 2030. In the Base Case, ReEDS uses the AEO's standard fuel price projection for coal and the high fuel price projection for natural gas.

Figure 7 illustrates the projected fossil fuel prices in constant 2004$. Values to the right of the vertical line in Figure 7 (at 2030) are extrapolations of EIA fuel price projections. The bands around the national averages are the range of average fuel prices for the NERC regions.

As mentioned, these are the baseline fuel price trajectories. ReEDS readjusts these forecasts annually based on demand, via short-term and long-term price elasticities. The elasticity calculations are explained in detail in Appendix C.

The price forecast for uranium is uniform across the country and is, like gas and coal, extracted from AEO 2008. Price elasticities are not applied to uranium.

2.6 Storage Technologies

There are four storage technologies currently implemented in ReEDS: pumped hydro storage (PHS), compressed air energy storage (CAES), batteries, and thermal (ice) storage. The battery chemistry assumed in the model—chosen on the basis of the current robustness of the technology and well-established and competitive costs—is sodium-sulfur. The cost/performance parameters for the storage technologies are in Table 19, below. Costs for each technology are for systems with eight hours of storage.

CAES is not a pure storage technology; for the storage portion, off-peak electricity is used to charge the reservoir, in this case by pumping high-pressure air into an underground cavern (e.g., a salt dome). Upon discharging, however, the compressed air is mixed with natural gas and combusted before expanding it through a turbine to generate power. In effect, CAES is a hybrid technology that uses electrical-to-physical storage to power a highly efficient combustion turbine; the heat rate of a CAES plant is roughly half that of a traditional natural gas plant. Because there are two inputs (electricity and natural gas), it is difficult to create a single

Table 19: Cost and Performance Characteristics for Storage Technologies

Plant Type	Install Year	Capital Cost ($/kW)	Fixed O&M ($/MW-yr)	Variable O&M ($/MWh)	Round Trip Efficiency	Heat Rate MMbtu/MWh
PHS	2005	1500	12720	5.0	0.72	-
PHS	2010	1500	12720	5.0	0.72	-
PHS	2020	1500	12720	5.0	0.72	-
PHS	2030	1500	12720	5.0	0.72	-
PHS	2040	1500	12720	5.0	0.72	-
PHS	2050	1500	12720	5.0	0.72	-
Battery	2005	1964	51000	5.0	0.77	-
Battery	2010	1964	51000	5.0	0.77	-
Battery	2020	1810	47002	5.0	0.78	-
Battery	2030	1668	43317	5.0	0.80	-
Battery	2040	1537	39921	5.0	0.81	-
Battery	2050	1417	36791	5.0	0.82	-
CAES	2005	840	10310	3.1	1.38	4.40
CAES	2010	840	10310	3.1	1.38	4.40
CAES	2020	820	10105	3.1	1.39	4.30
CAES	2030	820	10105	3.1	1.40	4.30
CAES	2040	820	10105	3.1	1.40	4.30
CAES	2050	820	10105	3.1	1.40	4.30
ice-storage	2005	14.22	2741	0.0	1.00	-
ice-storage	2010	14.22	2741	0.0	1.00	-
ice-storage	2020	14.22	2741	0.0	1.00	-
ice-storage	2030	14.22	2741	0.0	1.00	-
ice-storage	2040	14.22	2741	0.0	1.00	-
ice-storage	2050	14.22	2741	0.0	1.00	-

Source for Batteries: (EPRI-DOE 2003), CAES: (Holst 2005), Thermal Storage: (from FEMP 1994)

performance metric, so the table above includes both round-trip efficiency and heat rate. For every 0.72 MWh of electricity and 4.4 MMbtu of gas, the plant will provide 1 MWh of electricity.

There are 21 GW of utility-scale electric storage in use in the United States as of 2008, the vast bulk of which is PHS. A single 110 MW CAES plant operates in McIntosh, Alabama. Figure 8 shows regions in the country with appropriate geological features appropriate for CAES caverns (e.g., aquifers, domal salt, or bedded salt). In ReEDS, CAES is restricted in regions without appropriate geology, however, for regions with appropriate geology, the available capacity for CAES plants is currently not limited. Batteries can be installed anywhere.

The capacity of thermal storage is limited by the available air conditioning and heating loads. In ReEDS, thermal storage capacities are limited for every NERC region based on the total load of each NERC region (at every ReEDS timeslice), the fraction of the load associated with residential and commercial sectors separately, and the fraction of the load used for cooling and heating in each sector for each NERC region (at every ReEDS timeslice). The fraction of the load associated with residential and commercial sectors are derived from EIA 2009 data. The fraction of the load used for cooling and heating in each sector (by NERC region and timeslice) is forecasted by use of the NEMS model by LBL. Since thermal storage will likely not be installed for every building and home, ReEDS further reduces the allowed capacity for thermal storage by a multiplicative factor that exponentially grows from 2010 to 2050. This increasing multiplicative factor represents an estimated maximum adoption rate. Cost estimates for ice storage are derived from FEMP 1994.

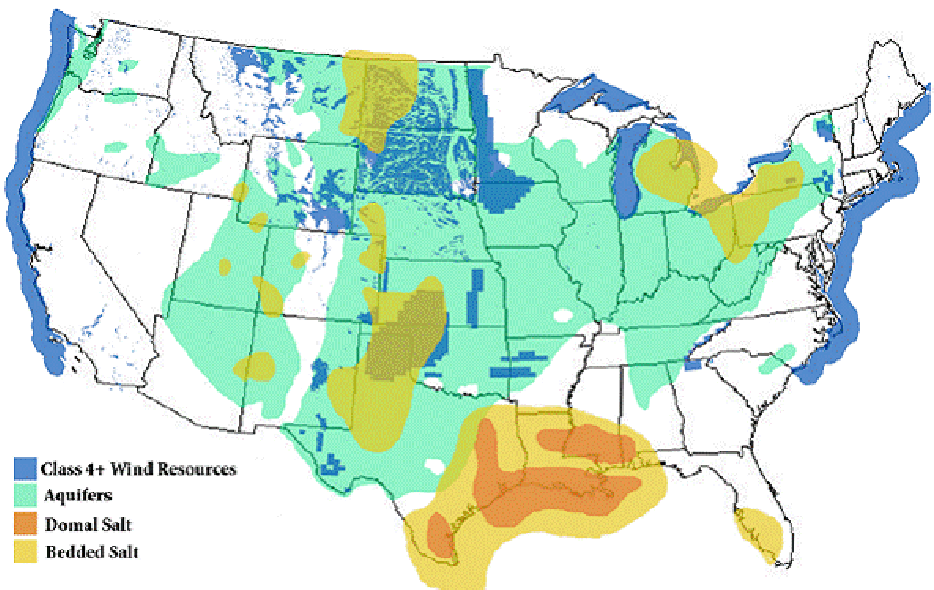

Figure 8: Areas with geology favorable to CAES, overlaid with class 4+ wind resource

2.7 Transmission

Three types of transmission systems can be used to transport wind power around the country, existing grid, new lines, and inregion transmission. In the case of transmission, "existing" means in existence at the start of the model, in 2006.

It is assumed that 10% of the existing grid can be used for new wind capacity, either by improving the grid or by tapping existing unused capacity (DOE 2008). A GIS optimization determines the distance at which a particular wind farm will have to be built to connect to the grid (based on the assumption that the closest wind installation will access the grid first at the least cost). In this way, a supply curve of costs to access the grid is created for each class of wind in each region. Additionally, a pancake-type fee for crossing between balancing areas may be charged within the model. The supply curves described earlier are based on this type of transmission and the GIS optimization described here. In the near term, one can expect that most of the wind that is built will use the existing grid, but as higher penetration levels are reached, the existing grid will be insufficient and new wind installation will require construction of new transmission lines.

Existing transmission capacity is estimated using a database of existing lines (length and voltage) from Platts Energy Market Data (2006). This database is translated into a megawatt capacity as a function of kilovolt (kV) rating and length (Weiss and Spiewak 1998).

Regarding new lines, the model has the ability to build straight-line transmission lines between the centers of any of the 356 resource regions. The line is built exactly to the size necessary to transmit the desired megawatts and the cost of building that transmission line is accounted for in the model. It is also noted that new wind- and csp- dedicated transmission lines are allowed to cross interconnect boundaries, whereas coventional transmission lines are not.

Experts on an AWEA panel for the "20% Wind Energy by 2030" report (DOE 2008) indicate that new transmission line capacity might be constructed for any generation technology for an average cost of $1,600/MW-mile. Based on input from the AWEA expert panel, regional transmission cost variations include an additional 40% in New England and New York; 30% in

PJM East (New Jersey and Delaware); 20% in PJM West (Maryland, West Virginia, Pennsylvania, Ohio, parts of Illinois, Indiana, and Virginia); and 20% in California.

The base case assumes that 50% of the cost of new transmission is borne by the generation technology for which the new transmission is being built (wind or conventional); the other half is borne by the ratepayers within a region (because of the reliability benefits to all users associated with new transmission). This 50-50 allocation, which is common in the industry, was recently adopted for the 15-state Midwest Independent Transmission System Operator (Midwest ISO) region. New wind transmission lines that carry power across the main interconnects are not cost-shared with other technology. In the base case, this sharing of costs is implied by reducing the cost of new transmission associated with a particular capacity by 50%. The remaining 50% of transmission costs are integrated into the final cost value outputs from the model, resulting in accurate total transmission costs.

In-region transmission: Within any of the 356 resource regions around the country, the model can build directly from a wind resource location to a load within the same region. A second GIS-generated supply curve is used within the model to assign a cost for this transmission.

The model treats a fourth type of transmission, used predominantly by conventional capacity and called general transmission. This is not frequently deployed because conventional capacity can generally be built in the region where it is needed, thereby obviating the need for new transmission.

ReEDS uses a transmission loss rate of 0.168 kW/MW-mile. This value is based on the loss estimates for a typical transmission circuit (Weiss and Spiewak 1998). The assumed typical line is a 200-mile, 230-kV line rated at 170 megavolt amperes (MVA; line characteristics derived from EPRI [1983]).

To emulate large regional planning structures based on that of the Midwest ISO, there is essentially no wheeling fee between balancing areas used in the base case (although the model has the capability to model such a fee).

2.8 Federal and State Energy Policy

2.8.1 Federal Emission Standards

The following emissions are tracked in ReEDS: SO_2, CO_2, NO_x, and Hg. All emissions are point-source emissions from the plant only (not "life-cycle" emissions).

ReEDS has the ability to impose a national cap on CO_2 emissions from electricity generation, or a CO_2 emission charge (tax). Neither a carbon cap nor charge is implemented in the Base Case.

Emissions of SO_2 are capped at the national level. The base case uses a cap that corresponds roughly to the 2005 Clean Air Interstate Rule (CAIR; EPA 2005a), replacing the previous limits established by the 1990 Clean Air Act Amendments. The CAIR rule divides the United States into two regions. ReEDS uses the EPA's estimate of the effective national cap on SO_2 resulting from the CAIR rule. Table 20 provides the SO_2 cap used in ReEDS. Because CAIR was struck down in the courts in 2008, we moved the ReEDS SO_2 limits schedule back four years; we will update the limits as more information becomes available or as developments occur.

Table 20: National SO_2 Emission Limit Schedule in ReEDS

	2003	2014	2019	2024	2034
SO_2 Cap (MTons)	10.6	6.1	5.0	4.3	3.5

Source: http://www.epa.gov/cair/charts_files/cair_emissions_costs.pdf

NO_x emissions are currently unconstrained in ReEDS. The NO_x cap based on the CAIR may be added, but the net effect on the overall competitiveness of coal is expected to be relatively small (EIA 2003). Also, adding a NO_x cap is complicated by the wide array of options available for NO_x control.

Mercury emissions are currently unconstrained in ReEDS. As of November, 2008, the Clean Air Mercury Rule (see `http://www.epa.gov/camr/index.htm`) is a cap-and-trade regulation, expected to be met largely via the requirements of CAIR. Control technologies for SO_2 and NO_x that are required for CAIR are expected to capture enough mercury to largely meet the cap goals. As a result, the incremental cost of mercury regulations is very low and is not modeled in ReEDS (EIA 2003).

2.8.2 Federal Energy Incentives

Two federal tax incentives for renewable energy are included in the ReEDS base case as shown in Table 21

Table 21: Federal Renewable Energy Incentives

	Value	Notes and Source
Renewable Energy PTC	\$19/MWh	Applies to wind. No limit to the aggregated amount of incentive. Value is adjusted for inflation to US\$2006. Expires end of 2009.
Renewable Energy ITC	30%	Applies to CSP. Expires end of 2016.
	10%	Applies to CSP after 2016.

2.8.3 State Energy Incentives

Several states also have production and investment incentives for renewable energy sources. The values used in ReEDS are listed in Table 22.

Table 22: State Renewable Energy Incentives

State	PTC ($/MWh)	ITC (%)	Assumed State Corporate Tax Rate (%)
Iowa	-	5.0	10.0
Idaho	-	5.0	7.6
Minnesota	-	6.5	9.8
New Jersey	-	6.0	9.0
New Mexico	10	-	7.0
Oklahoma	2.5	-	6.0
Utah	-	4.75	5.0
Washington	-	6.5	0.0
Wyoming	-	4.0	0.0

Investment and production tax credit data from IREC (2006) Tax rates from:
`http://www.taxadmin.org/fta/rate/corp_inc.html`

2.8.4 Federal Renewable Portfolio Standards

A renewable portfolio standard (RPS) requires that a certain fraction of a region's energy be derived from renewable sources. While there is no federal RPS in place (as of August, 2009) or in the ReEDS Base Case, ReEDS can accommodate a national RPS, with input values for fraction of energy to be provided by renewables, RPS start year, duration, and shortfall penalty.

2.8.5 State Renewable Portfolio Standards

A number of states have legislated RPS requirements, and states can put capacity mandates in place as an alternative or supplement to an RPS. A capacity mandate requires a utility to install or generate a certain fixed amount of renewable capacity or energy. Unless prohibited by law, a state might also meet requirements by importing electricity. The ReEDS Base Case enforces the legislated state standards listed in Table 23.

2.9 Future Work

We continue to update and improve the data in the ReEDS Base Case as it becomes available. The data relating to electric loads and fuel prices, and conventional technology costs and performance are updated annually, coincident with the release of the full Annual Energy Outlook dataset.

As mentioned above, it is our intent to improve the treatment—particularly where regional differences are concerned—of carbon capture and sequestration. Regions where there are geological features suitable for sequestration will have lower CO_2 transportation costs than regions that have to ship their exhaust hundreds of miles. Ideally, we would also put annual and total capacity caps on the amount of CO2 a given area would be able to sequester and force ReEDS to build a piping network complete with flow limits to transport the CO_2.

We also plan to modify ReEDS to include other generation sources (e.g. central PV, ocean power, etc.), and characteristics of the electricity sector (e.g. incorporating transportation–EVs and PHEVs, and demand response).

Table 23: State Renewable Portfolio Standards

State	RPS Start[2]	Full Implementation[3]	Penalty ($/MWh)	Assumed RPS (%)[4]	Legislated RPS (%)[5]	Load Fraction[6]
Arizona	2001	2025	5	15	15	0.59
California	2003	2011	50	20	20	0.75
Colorado	2007	2015	5	30	30	0.51
Connecticut	2004	2020	55	23	27	0.93
Delaware	2007	2020	5	36	40	0.36
Illinois	2004	2025	5	25	25	0.46
Iowa	1999	1999	5	105 MW	105 MW	1
Massachusetts	2003	2020	59	15	15	0.85
Maryland	2006	2022	20	20	20	0.97
Michigan	2007	2015	5	10	10	1
Minnesota	2002	2025	5	55	55	0.50
Missouri	2007	2021	5	15	15	0.70
Montana	2008	2015	10	15	15	0.67
Nevada	2003	2015	5	20	20	0.88
New Hampshire	2008	2025	54	23.8	23.8	1
New Jersey	2005	2021	50	22.5	22.5	0.98
New Mexico	2006	2020	5	29.4	30	0.52
New York	2006	2013	5	23.7	23.8	0.73
North Carolina	2007	2021	5	21	22.5	0.53
Ohio	2007	2024	45	12.5	12.5	0.89
Oregon	2002	2025	5	40	40	0.51
Pennsylvania	2007	2021	45	17.5	18	0.97
Rhode Island	2007	2019	59	16	16	0.99
Texas	2003	2015	50	5,880 MW	5,880 MW	1
Washington	2007	2020	50	15	15	0.85
Wisconsin	2001	2015	10	10.1	10.1	1

Notes:1) RPS data as of 8/16/05. (IREC 2006)
2) RPS Start Year is the "beginning" of the RPS program. The RPS is ramped up to the full implementation level beginning in the start year. The ramp is linear unless specified otherwise in the legislation.
3) RPS Full Implementation is the year that the full RPS fraction must be met.
4) Assumed RPS is the fraction of state demand that must be met by renewable resources included in the ReEDS model. The value is based on the total state RPS requirement and adjusted to estimate the fraction actually provided by technologies in ReEDS; for instance, new or small hydropower is not included in ReEDS so a state with a hydro set-aside would have its RPS lowered by the appropriate amount.
5) Legislated RPS is the full value of the RPS as legislated by the individual states.
6) Load fraction is the fraction of the total state load that must meet the RPS. In many locations, municipal or cooperative power systems may be exempt from the RPS. The final level used in ReEDS is the assumed RPS multiplied by the applicable load fraction.